July 29, 2002

U.S. Nuclear Regulatory Commission   10 CFR 50.73
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT (SQN) UNIT 2 - DOCKET NO. 50-328- FACILITY OPERATING LICENSE DPR 79 - LICENSEE EVENT REPORT (LER) 50-328/2002003

The enclosed report provides details concerning an automatic reactor trip from a high generator stator cooling water temperature resulting from a failure of a raw cooling water isolation valve. This event is being reported, in accordance with 10 CFR 50.73(a)(2)(iv), as an event that resulted in an automatic actuation of the reactor protection system. This letter is being sent in accordance with NRC RIS 2001-05.

Sincerely,

Original signed by

Richard T. Purcell

Enclosure
cc (Enclosure):
INPO Records Center
Institute of Nuclear Power Operations
700 Galleria Parkway
Atlanta, Georgia 30339-5957

NRC FORM 366 (7-2001)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
Sequoyah Nuclear Plant (SQN) UNIT 2	05000328	1 OF 07

4. TITLE
Automatic Reactor Trip Resulting from a Generator Stator Cooling Water High Temperature Caused by a Raw Cooling Water Valve Failure

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
05	31	2002	2002	– 003 –	00	07	29	2002	FACILITY NAME	DOCKET NUMBER

9. OPERATING MODE	1
10. POWER LEVEL	071

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

[redacted]

20.2203(a)(2)(ii) | 50.36(c)(2) | 50.73(a)(2)(v)(B) | OTHER Specify in Abstract below or in NRC Form 366A

[redacted]

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
James Proffitt	(423) 843-6651

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
X	TJ	VLV	P340	Y					

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	NO				

16. ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)

On May 31, 2002, at 0116 Eastern Daylight Time the Unit 2 turbine tripped followed by a reactor trip as a result of an actuation of the main generator stator cooling water failure circuit. Prior to the trip, Operations personnel observed increased temperature on the generator stator cooling water system. Indications show that the generator stator cooling water temperature reached the setpoint then actuated as required. The main control room operators took appropriate actions to stabilize the reactor in hot standby (Mode 3). The generator stator cooling water high temperature was the result of a raw cooling water isolation valve failure causing low flow to the stator cooling water system heat exchanger. The raw cooling water valve was replaced.

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NARRATIVE (If more space is required, use additional copies of NRC Form 366A) (17)

I. PLANT CONDITION(S)

Unit 2 was in Mode 1 at approximately 71 percent reactor power. Operations was in the process of increasing power.

II. DESCRIPTION OF EVENT

A. Event:

On May 31, 2002 at 0116 Eastern Daylight Time (EDT) the turbine tripped followed by a reactor trip as a result of an actuation of the main generator stator cooling water failure circuit (EIIS Code TJ). Prior to the trip, Operations personnel observed increased temperature on the generator stator cooling water system. Operations personnel were trying to ensure proper cooling water flow was available to the stator cooling water system when the trip occurred. Indications show that the generator stator cooling water temperature reached the setpoint then actuated as required. The main control room operators took appropriate actions to stabilize the reactor in hot standby (Mode 3).

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times of Major Occurrences:

May 30, 2002 at ~1709 EDT	Stator Temperatures begin to increase. Generator tied online at about this time.
May 31, 2002 at 2146 EDT	The generator stator temperature high alarms. Operations begins to investigate and take actions to ensure proper cooling flow to the generator stator cooling system.
May 31, 2002 at 0115 EDT	The generator stator cooling system failure alarm actuates.

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May 31, 2002 at 0116 EDT	The generator stator cooling failure turbine trip alarm and reactor trip alarm annunciated in the main control room.
May 31, 2002 at 0133 EDT	Operations completed actions to secure equipment and stabilize plant in Mode 3.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

The main generator stator cooling water failure circuit alarm and subsequent turbine and reactor trips annunciated on the main control room panels.

F. Operator Actions:

Control room operators responded to the event in accordance with plant procedures. They promptly diagnosed the plant condition, took the actions necessary to stabilize the unit, and maintained the unit in hot standby, Mode 3.

G. Safety System Responses:

The plant responded to the turbine and reactor trips, as designed with the exception of a Rod Cluster Control Assembly (RCCA) that showed a delayed insertion into the core below approximately 17 steps withdrawn during the reactor trip.

III. CAUSE OF THE EVENT

A. Immediate Cause:

The immediate cause of the event was the actuation of the high generator stator cooling water failure circuit. The high temperature was the result of loss of raw cooling water flow to the stator cooling water heat exchanger.

B. **Root Cause:**

The root cause of the event was the loss of raw cooling water flow to the generator stator cooling water system resulting from a manual isolation supply valve to stator cooling water heat exchanger blocking flow due to internal damage. The valve disk was found split down the shaft.

C. **Contributing Factors:**

A contributing factor to this event was the decision by Operations personnel to apply supplemental force to the valve, rather than evaluating the cause of the difficulty in opening the valve.

IV. ANALYSIS OF THE EVENT

The plant safety systems responses during and after the unit trip were bounded by the responses described in the Final Safety Analysis Report.

V. ASSESSMENT OF SAFETY CONSEQUENCES

Based on the above Analysis of The Event, this event did not adversely affect the health and safety of plant personnel or the general public.

VI. CORRECTIVE ACTIONS

A. **Immediate Corrective Actions:**

An investigation was performed to determine the cause of the loss of cooling water to the generator stator cooling water system. It was determined that the raw cooling water isolation valve did not open as indicated. An analysis of the valve failure is provided below.

B. **Corrective Actions to Prevent Recurrence:**

The raw cooling water valve was replaced.

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Guidance on the use of supplemental force and expectations for personnel performance when field components do not perform as expected is being developed.

VII. ADDITIONAL INFORMATION

A. Failed Components:

A raw cooling water butterfly valve (Henry Pratt Model 2FII) failed. This valve is an 8-inch, hand wheel operated, valve, which is the raw cooling water inlet isolation valve to the Unit 2 stator cooling water heat exchanger. During restart activities following the refueling outage, Operations personnel tried to open the raw cooling water valve to the generator stator cooling water system. When the stem would not turn because the disk was bound into the seat, a supplemental force was used to force stem rotation.

The supplemental force caused the pre-existing crack in the valve disk to crack completely down the disk. Additional use of the supplemental force caused the shaft pin to rotate into the disk hole, splitting the disk apart and allowing flow through the center of the disk.

After the disk was pushed into the rubber seat far enough to add additional resistance to rotation, the shear key sheared and the valve operator turned freely to its stop. This gave the operators the impression that the valve was full open and the valve position indicator was reading incorrectly.

B. Previous LERs on Similar Events:

A review of previous reportable events for the past three years did not identify any similar events.

C. Additional Information:

The rod position indicator (RPI) trace of Shutdown Bank A RCCA at core location L-11 showed a delayed insertion into the core below approximately 17 steps withdrawn during the reactor trip. However, as explained below, it does not appear that the indicated delayed insertion was the result of excessive swelling of the rodlet tips (i.e., generic industry issue). Troubleshooting continues to rule out other possible causes such as debris, mechanical interference with RCCA/drive shaft, or fuel assembly bowing.

Previous eddy current wear measurements were made on the Unit 2 RCCAs during the Cycle 7 refueling outage. This RCCA had the lowest wear measured on any Unit 2 RCCAs. This RCCA has accumulated approximately 13.4 effective full power years of exposure. The possible crack indications measured were approximately 5.3 inches (longest indication) on 5 rodlets. The possible crack indications provides the extent of hairline axial cracking of the rodlet tips because of fluence-induced swelling of the Ag-In-Cd absorber. The possible crack indications of this RCCA was on the lower end of the bulk of indications measured on the Unit 2 RCCAs. This RCCA has not been in Control Bank D since the Cycle 7 refueling outage and, should not have accumulated excessive additional fluence on the rodlet tips.

During the U2C11 refueling outage, RCCA drag testing showed normal values both before the unlatching at the start of refueling and after the post-refueling latching. RCCA drop time testing following the refueling outage showed normal trace characteristics with fast speed from trip to dashpot entry. The characteristic "bounce" was present indicating full insertion, proving operability. Subsequent additional rod drop time testing was performed after the problem RPI L-11 response was detected which showed acceptable Technical Specification drop time. The delayed insertion of the RCCA into the core could not be repeated during testing. Therefore, the condition observed for this RCCA during the reactor trip was determined acceptable. The rod inserted sufficiently to perform its function; therefore, this is not considered a safety system functional failure.

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Given these facts, this RCCA does not appear to be a good candidate for excessive swelling of the rodlet tips that might lead to binding in the dashpot region during rod insertion and result in delayed full-insertion times.

Based on industry information related to problems with aging of RCCAs, the Unit 2 RCCAs are scheduled to be replaced during the next refueling outage.

D. **Safety System Functional Failure:**

This event did not result in a safety system functional failure in accordance with NEI 99-02.

VIII. COMMITMENTS

None.